

**STATE OF NEW YORK
PUBLIC SERVICE COMMISSION**

Proceeding on Motion of the Commission)
Assessing Implementation of and)
Compliance with the Requirements and)
Targets of the Climate Leadership and)
Community Protection Act)

Case 22-M-0149

**JOINT UTILITIES' PROPOSAL FOR
AN ANNUAL GREENHOUSE GAS
EMISSIONS INVENTORY REPORT**

I. Introduction

The Joint Utilities of New York¹ submit this proposal for an annual Greenhouse Gas (GHG) Emissions Inventory Report. On May 12, 2022, the New York State Public Service Commission (Commission) issued an Order on Implementation of the Climate Leadership and Community Protection Act (CLCPA).² The Commission directed the Joint Utilities to work with Department of Public Service Staff (DPS Staff) to develop a proposal for an annual GHG Emissions Inventory Report, including detailed requirements and the methodology used to calculate total natural gas system-wide emissions, and file a draft version for public comment by December 1, 2022. The Commission further directed the Joint Utilities to follow the methodology required in the CLCPA and by the New York State Department of Environmental Conservation (DEC) to calculate their system emissions, noting that: “The goal is for the Utilities to assess the

¹ Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, National Fuel Gas Distribution Corporation, Liberty Utilities (St. Lawrence Gas) Corp., and Corning Natural Gas Corporation.

² Case Number 22-M-0149, Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act, Order on Implementation of the Climate Leadership and Community Protection Act (issued May 12, 2022) (Order).

current direct and indirect GHG emissions, including upstream emissions from imported fossil fuels, local distribution emissions, and end-use (customer meter) emissions and file a report on an annual basis.”³

Accordingly, the Joint Utilities have developed an emissions inventory reporting mechanism that best represents our specific industry and herein present this proposal for an annual GHG emissions inventory report, as well as the requirements and methodology to be used to determine their gas system-wide emissions for that report. The remainder of this proposal provides an overview of current GHG reporting practices; describes the Joint Utilities’ proposed methodology for annual reporting of direct and indirect emissions, emissions associated with operational activities (including “avoided emissions”), and upstream emissions; and proposes a common framework that would be used by the State’s gas utilities in reporting their respective annual GHG emissions inventories.

II. Overview of Current GHG Estimation Principles

As described below, there are two principal methodologies currently used by reporting entities to report GHG emissions: the Greenhouse Gas Reporting Program (GHGRP) and the Greenhouse Gas Inventory (GHGI). This section is intended to be an overview for readers less familiar with the current state of GHG emissions reporting.

- The US Environmental Protection Agency’s (EPA) Mandatory GHGRP requires various industries to report GHG emissions annually. For the natural gas industry, the regulations are found at 40 CFR Part 98, Subpart W.

³ Order at 15. In addition, the Order directed the Joint Utilities to include, in all future rate filings, an assessment of the impacts that the utility’s specific investments, capital expenditures, programs and initiatives included in the rate filing will have on its GHG emissions from its natural gas network, specifying the potential emissions impacts of each. *Id.* at 16.

- Subpart W divides the natural gas industry into ten segments, each of which has a 25,000 MT CO₂-e/year reporting threshold.
- In the natural gas distribution segment, emissions sources are limited to mains, services, metering and regulating (M&R) stations, and certain types of combustion units.
- Emissions estimates for mains and services are calculated from emission factors. The emissions factors for mains and services are broken out by material of construction (i.e., protected steel, unprotected steel, plastic, and cast iron).
- For each asset/material combination, emissions are determined by multiplying the emission factor by the “population.” In the case of mains, the population is miles of main; in the case of services, the population is number of services.
 - For example, the emissions from plastic mains are calculated by multiplying the emission factor for plastic mains by the miles of plastic mains in a utility’s service territory.
- The emission factors used for GHGRP reporting derive from a 1996 GRI/EPA study.⁴
- Local distribution companies (LDCs) meeting the reporting threshold have been reporting emissions to EPA using this method since 2011. These reports are publicly available on EPA’s FLIGHT website.⁵
- The GHGI⁶ is a national estimate of GHG emissions prepared annually by EPA and submitted to the United Nation’s (UN) Framework Convention on Climate Change.

⁴ *Methane Emissions from the Natural Gas Industry, Vol. 9: Underground Pipelines*, GRI/EPA DCN 95-263-081-16, June 1996, L. Campbell, M. Campbell, and D. Epperson.

⁵ <https://www.epa.gov/ghgreporting/data-sets>.

⁶ <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks>.

- For natural gas distribution systems, the GHGI includes the same sources as the GHGRP, but adds customer meters, pressure relief valves (PRVs), blowdowns, and dig-ins (damages).
- Emissions from all of the sources cited above are based on emission factors applied to a population (primarily miles of main or number of meters).
- For mains and services, EPA adopted emission factors from a 2015 study by Washington State University⁷ for GHGI reporting. In most cases, the emissions factors for mains and services used for GHGI reporting are lower than those in the GHGRP, reflecting improved leak management as compared to the 1996 GRI/EPA study.
- Because the GHGI is not a regulation, EPA has flexibility to incorporate emerging research/data more easily.
- Industry standards, such as the Natural Gas Sustainability Initiative (NGSI)⁸ and ONE Future,⁹ are modelled on the GHGI since it is more comprehensive, and the emission factors are more current.
- Many utilities follow the NGSI methodology in their voluntary reporting. In addition, NGSI has been adopted by certification bodies such as MiQ (developed by the Rocky Mountain Institute)¹⁰ and Equitable Origin.¹¹

⁷ *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States, Environmental Science and Technology*, B. Lamb, et. al., 2015, 49, 1561-1569.

⁸ <https://www.eei.org/issues-and-policy/NGSI>.

⁹ <https://onefuture.us/>.

¹⁰ <https://rmi.org/press-release/rocky-mountain-institute-rmi-and-systemiq-launch-miq-to-tackle-methane-emissions-from-the-oil-and-gas-sector/>.

¹¹ <https://www.equitableorigin.org/adopt-eo100/>.

The Joint Utilities' proposal uses the most updated data from the aforementioned sources and applies those data to the broadest set of facilities to arrive at a proposed annual GHG reporting methodology.

III. Joint Utilities' Proposal for GHG Reporting

The Joint Utilities are proposing to use the NGSI methodology, modified as described below, for their annual GHG Inventory reporting. In addition to being more comprehensive and reflective of current research, NGSI has developed a template that can be readily adapted to the requirements of the Order and is supported by a well-developed protocol. The Joint Utilities are, however, proposing to modify the NGSI methodology regarding the determination of carbon dioxide equivalent (CO₂e) emissions from emission sources. Specifically, the Joint Utilities will use a global warming potential (GWP) integrated over a 20-year time horizon for emissions including methane (CH₄) and nitrous oxide (N₂O), rather than reporting only CH₄ as required in the base NGSI methodology. This modification will make the methodology consistent with the requirements of the CLCPA and the DEC Statewide Inventory.

The Joint Utilities are proposing to use the modified NGSI methodology in lieu of the DEC's current methodology because the proposed approach applies to a greater population of facilities and uses more updated data. The DEC's current Statewide Inventory methodology accounts only for emissions from natural gas system mains, services, and customer meters, and therefore is less comprehensive than the NGSI, which includes additional facilities and activities (*i.e.*, PRVs, blowdowns, damages). In addition, the DEC methodology does not include the most current emissions factors from the GHGRP for mains and services; while for meters it uses emissions factors from the GHGI. The modified NGSI methodology, on the other hand, uses the more updated GHGI factors for mains and services. As a result, the Joint Utilities' proposal is

both more comprehensive and reflective of updated emissions factors than the approach used by DEC. It should be adopted by the Commission for use by the Joint Utilities for their annual GHG reporting.

Finally, it should be noted that estimating emissions from emissions factors has a number of limitations. For distribution systems, the most significant limitation is that once a system is fully modernized, no further estimated reduction in emissions is possible regardless of an LDC's leak management practices. However, as technology advances, it is becoming viable for LDCs to *measure* emissions at scale instead of relying on *estimates* from emission factors. Therefore, the Joint Utilities recommend that the Commission allow flexibility for the GHG Inventory Report to include leak quantification in future versions. There are currently two protocols centered on measurement and reconciliation: the Oil and Gas Methane Partnership (OGMP) and GTI Veritas.

A. GHG Reporting Considerations

The Joint Utilities propose to use a scientifically valid methodology for each segment of the gas value chain that allows and accounts for inputs from utility investments and operational performance. Important considerations include how to incorporate certified gas, replacement of mains and services, and other utility initiatives intended to reduce emissions. The Joint Utilities' proposal presents a methodology that addresses such considerations and can be adopted by all LDCs in the State.

The Joint Utilities' proposal employs a consistent methodology for estimating GHG emissions, so that LDCs do not report inconsistent emissions levels for the same period. Industry emissions reporting continues to evolve, allowing improved precision in evaluating upstream emissions, as discussed below in the upstream methodology section of this report. Furthermore, technological advancements likely will produce greater precision in the entire inventory process

over time, so it is important to maintain a level of flexibility to adopt better and more precise methodologies.

B. Attributable and Avoided Emissions

The Joint Utilities propose to determine and quantify two types of emissions at the local distribution level: (1) emissions associated with system attributes (attributable emissions), and (2) emissions associated with recognized emission reduction initiatives (avoided emissions).

Attributable Emissions

Attributable emissions quantification would be based on the NGSI reporting methodology developed by the American Gas Association (AGA) and the Edison Electric Institute (EEI). NGSI is widely used across the natural gas industry as a common framework for the voluntary disclosure of methane emissions. The NGSI protocol uses EPA-derived emission factors, includes distribution system attributes (e.g., main material, service material, M&R stations), and includes emissions factors for outdoor residential meters and commercial/industrial meters from the GHGI. This approach would therefore capture customer meter emissions, as required by the Order.

Attributable emissions can only be reduced by upgrading leak-prone materials, but may increase if the number of new facilities (e.g., services, meters) in the system increases. Any reductions or increases reported using the NGSI protocol will be consistent with EPA requirements under 40 CFR Part 98 and in EPA's GHGI reports to the UN.

Avoided Emissions

Reporting avoided emissions reveals the magnitude of a utility's initiatives that may not be captured by estimates based on emission factors. Avoided emissions are necessary to include in the GHG Inventory Report to justify future investments and programs. As required in the Order,

in all future rate filings, utilities are to provide an assessment of the impacts specific investments, capital expenditures, programs and initiatives included in the rate filing will have on GHG emissions from its gas network, specifying the potential emissions impacts of each.¹²

Utilities are approaching emission reductions in different ways, and as such, they calculate and report avoided emissions in a variety of ways. Because emission reduction techniques may be influenced by the specific circumstances of each utility's gas system, there is currently no commonly accepted protocol in the natural gas industry that is applicable for reporting avoided emissions. For this reason, the Joint Utilities propose that the Commission allow flexibility in how the Joint Utilities report avoided emissions. As an example of possible approaches to report avoided emissions, utilities may consider using the EPA's Methane Challenge methodologies. Utilities may also report avoided emissions in terms of use of renewable fuels, enhanced leak response time, reduced leak backlog, ZEVAC use/blowdown reduction, and/or dig-in reductions.

Next year, the World Resources Institute (WRI) will undertake an update of Scope 2 and 3 emissions reporting under the GHG Protocol (GHGP). WRI has also recently issued a GHGP Land Sector and Removals Protocol Guidance document with biomethane carbon accounting guidance. In addition, the Securities and Exchange Commission (SEC) and International Sustainability Standards Board (ISSB) have issued proposals that will require climate-related disclosures as part of financial filings. These sources may provide further guidance to aid in the determination and reporting of avoided emissions.

C. Upstream Emissions

The Joint Utilities describe below a proposed methodology for estimating upstream emissions of greenhouse gases. "Upstream emissions" include losses associated with the

¹² Order at 16, and Ordering Clause 3.

production, gathering and boosting, storage and transmission of the natural gas value chain. Each of the utilities in the State is required to estimate and report on the GHG emissions associated with its purchases of natural gas that are delivered to its service territory.

NYSERDA research¹³ has shown that very little natural gas is produced in New York State, so the challenge for this methodology is to ascribe emissions to facilities in other parts of the country. The National Energy Technology Laboratory (NETL), a world-class research institution, has published, and continues to update, an extensive analysis of the GHG emissions associated with the parts of the natural gas value chain associated with different production basins in the United States. As discussed later in this report, NETL's research has been utilized as the foundation for NYSERDA's support of the analysis conducted by the DEC in their development of 6 NYCRR Part 496. The reporting of upstream emissions by the Joint Utilities on an annual basis will provide valuable information in support of DEC's annual greenhouse gas inventory process.

The specific reports published by the NETL that contributed to the development of this methodology include the following:

*NETL Reference 1: J. Littlefield, S. Roman-White, D. Augustine, A. Pegallapati, G. G. Zaines, S. Rai, G. Cooney, T. J. Skone, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," National Energy Technology Laboratory, Pittsburgh, April 5, 2019.

*NETL Reference 2: S. Rai, J. Littlefield, S. Roman-White, G. G. Zaines, G. Cooney, T. J. Skone, "Industry Partnerships & Their Role in Reducing Natural Gas Supply Chain Greenhouse Gas Emissions – Phase 2," National Energy Technology Laboratory, Pittsburgh, February 12, 2021.

*NETL Reference 3: Timothy J. Skone, P.E., "Industry Partnerships and their role in reducing natural gas supply chain greenhouse gas emissions," National Energy Technology Laboratory, Pittsburgh, May 1, 2018.

¹³ New York State Energy Research and Development Authority (NYSERDA). 2021. "New York State Oil and Gas Methane Emissions Inventory: 2018–2020 Update," NYSERDA Report Number 21-31. Prepared by Abt Associates, Rockville, MD. nysERDA.ny.gov/publications.

*NETL Reference 4: Timothy J. Skone, P.E.; James Littlefield; Selina Roman-White, “Methods and Data to Account for Upstream Emissions from Coal and Natural Gas: EPRI GHG Emissions Accounting for Electric Companies,” April 29, 2021.

The NETL work is not limited to CH₄ alone but includes all the major greenhouse gases including CO₂ and N₂O. The NETL research, consistent with a wide range of GHG inventories, notes that N₂O emissions from losses are orders of magnitude smaller than the CH₄ and CO₂ emissions. Therefore, the discussion of emission factors below will disregard N₂O emissions as immaterial.

Assigning emission factors to different types of gas

To evaluate the upstream emissions associated with the procurement of natural gas, and to assign an emission factor to a particular purchase of natural gas, it is necessary to identify the “pedigree” or “origin” of that purchase. This methodology recognizes three types of gas purchases: gas with a known point of origin, certified gas, and “spot gas” or undifferentiated gas with no known point of insertion into the overall gas transmission system.

“Gas with a known point of origin” is gas that is contracted for from a particular nomination point. To illustrate a number of points associated with this methodology, an actual purchase by a utility is described. A utility contracted for a supply of 644,000 dekatherms (Dth) from a supplier from a nomination point called “Tombs Run.” Tombs Run is in the southwest corner of Pennsylvania, near the border with West Virginia, so the gas supplied there is described as Appalachian Basin gas. Using the NETL data, an emission factor can be ascribed to that shipment of gas. The data in Figure 1 below (shown in grams of CO₂e per megajoule, 20-year GWP) is adapted from page E-34 of NETL Reference 1 (above).

Figure 1 – Select Emissions Factors from NETL Ref. 1 (grams of CO₂e per megajoule, 20-year GWP)

Scenario	Mean CO ₂ e for specific GHGs			Total CO ₂ e, 20-year GWP ¹⁴		
	CO ₂	CH ₄	N ₂ O	P2.5	Mean	P97.5
National Average	12.0	18.9	0.0378	20.7	30.9	44.5
Appalachian Shale	10.7	13.3	0.0344	15.7	24.1	33.4

The NETL emission factors listed include all CO₂, CH₄, and N₂O emissions for the entire value chain, including distribution losses. To avoid double counting within the overall proposed methodology, the basin-based emission factors from the NETL report have been reduced to delete the losses associated with distribution. Consultation with the authors of the NETL studies indicate that it is appropriate to reduce the emission factors by basin by approximately 10% to account for distribution system losses in the NETL report.¹⁵ Thus, the emission factor shown on page E-34 of the NETL Reference 1 report – 24.1 grams of CO₂e per megajoule, 20-year GWP (g/MJ, GWP 20) -- is reduced to 21.6 g/MJ, GWP 20. This adjusted value can then be multiplied by the 644,000 Dth purchased from a nomination point at Tombs Run to calculate the emissions, expressed in metric tons of CO₂e, 20-year GWP, associated with that purchase.

Figure 2 below shows the described calculation:

¹⁴ NETL analyses uses a GWP multiplier of 87 to get to a 20-year GWP CO₂e for CH₄ based on a conservative reading of Table 8.7 of the IPCC Assessment Report No. 5 by including climate-carbon feedback and a value of 1 for methane oxidation. The value of 87 is used throughout this document to be consistent with the NETL analysis even though other values may be used in more recent State and Federal studies and utility reports. Table 8.7 can be found on page 714 of the following document: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

¹⁵ Personal correspondence with Matt Jamieson, NETL, Senior Life Cycle Analyst: "...a more accurate approach to remove the distribution losses is to work with the emission amounts directly. Distribution losses for the 2016 data have a mean of 1.02E-05 kg CO₂/MJ and 2.86E-05 kg CH₄/MJ (Exhibit F-31 in the report) and are the same across all scenarios. If I were to convert those to GWP using the factors from our report (87 for methane @ 20-yr), then I get 24.1 – 2.5 = 21.6 g CO₂e/MJ, which is ~10% reduction from 24.1 g CO₂e/MJ." The report noted is NETL Reference 1.

Figure 2 – Example Calculation for Upstream Emissions Methodology

<u>Example Purchase:</u> Gas nominated from a connection in Appalachian Basin <u>Conversion Note:</u> 1 Dth = 1 million Btu = 1 MMBtu = 1055.0559 megajoules		
Gas purchased, in Dth	644,000	
convert to MJ (Dth times 1055.0559)	679,456,000	
Calculate upstream emissions using NETL emission factor for Appalachian Basin of 21.6 grams/MJ CO ₂ e, 20-year GWP [includes all emissions except distribution emissions, calculated with support from NETL staff]	14,676,249,591	grams CO ₂ e, 20-year GWP; this factor includes both CH ₄ and CO ₂
Convert grams to metric tons (1 g = 1.0E-6 metric tons)	14,676	metric tons CO ₂ e, 20-year GWP

Thus, for that one purchase – with gas from a known point of origin – the upstream emissions totaled 14,676 metric tons of CO₂e expressed using a 20-year global warming potential. To give some context to the magnitude of this value, the NYSERDA research noted above indicates that CH₄ emissions (alone) from oil and natural gas industry in New York State totaled 12,460,067 metric tons CO₂e, GWP 20 in 2020.

The second type of gas to be accounted for in the upstream segment is “**certified gas**,” sometimes referred to as “differentiated gas.” Certified gas is procured from suppliers that have adopted stringent management practices and emission reduction initiatives. The CH₄ emission rate from their supply has been evaluated by independent third-party assessors and the gas that supplier offers to the marketplace is “certified” to have a particularly described CH₄ emission rate. For the purposes of illustration here, a CH₄ emission rate of 0.10% is assumed for the same shipment of 644,000 Dth.

Inasmuch as certified gas descriptors refer to a CH₄ emission rate, and the emission rates listed in the NETL reports include both CO₂ and CH₄, the NETL emission factors must once again

be adjusted to reflect this difference. With consultation with the authors of the NETL report, the CH₄ emission rate for Appalachian Basin gas is shown as 0.12%.¹⁶ This low CH₄ emission rate is typical of the Appalachian Basin because of the geomorphology and the prevailing well technology of the region. Substituting a 0.10% CH₄ emission rate (the certified rate) for the known 0.12% basin emission rate yields an overall emission factor for certified gas from the Appalachian Basin of 21.297 g/MJ CO₂e, GWP 20. Repeating the calculation shown above but with the lower emission factor associated with certified gas, yields 14,470 metric tons of CO₂e expressed using a 20-year global warming potential.

Certified gas is also available with an emission rate of 0.05% CH₄; if such gas was purchased, the emission factor could be adjusted in the same manner and the calculation for such a shipment would be similar.

The final type of possible gas purchase is “**undifferentiated gas.**” Undifferentiated gas is purchased by utilities at the city gate or at a point along the pipeline that is deemed a “liquid receipt point” to meet customer demand and is purchased without reference to a particular nomination point. To determine the upstream emissions associated with this type of purchase, it is appropriate to use the emission factor that the NETL research assigns to the “National Average.” NYSERDA research¹⁷ indicates that Texas and Pennsylvania are the largest producers of natural gas in the United States. As shown in Figure 3 below,¹⁸ the range of emissions factors from basins in those two states show a wide variety of emission factors, with most of the Pennsylvania basins to the right of (i.e., below) the national average, and most of the basins in Texas to the left of (i.e., above)

¹⁶ The actual calculation is shown in Appendix A.

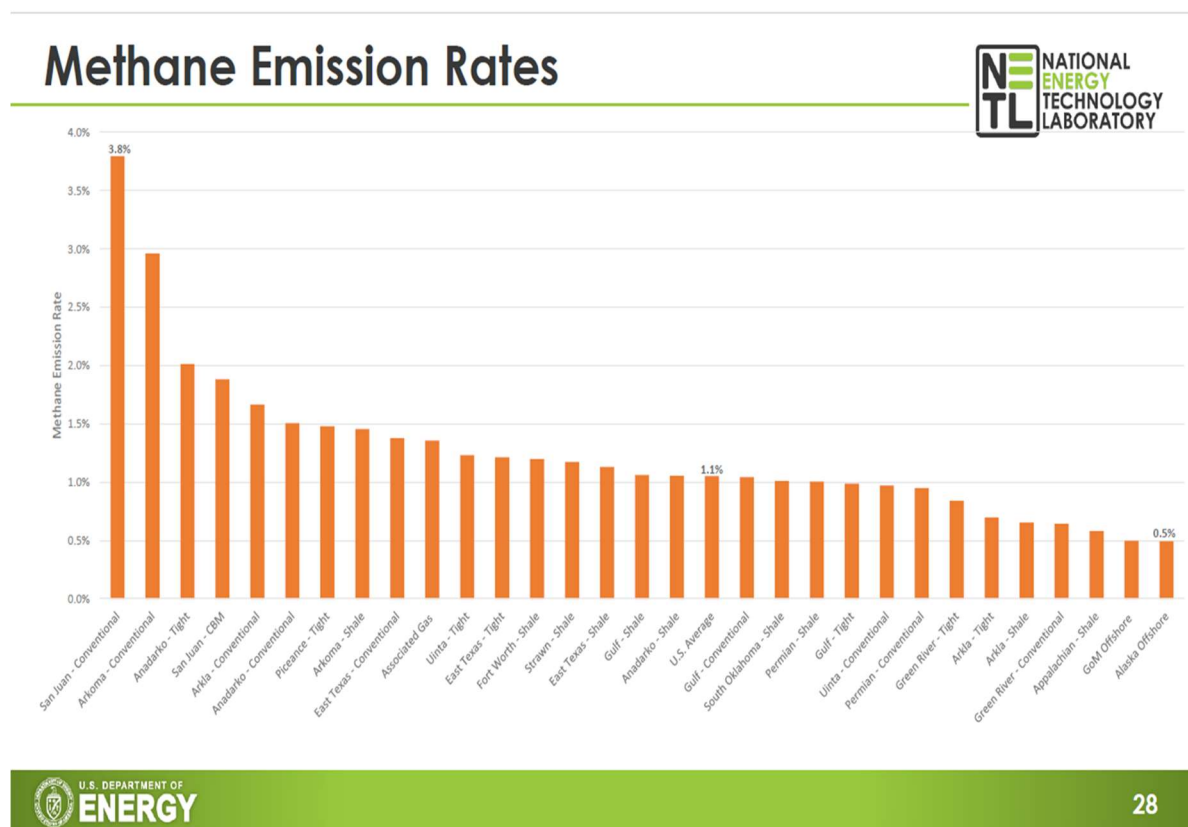
¹⁷ New York State Energy Research and Development Authority (NYSERDA). 2019. “New York State Oil and Gas Sector Methane Emissions Inventory.” NYSERDA Report Number 19-36. Prepared by Abt Associates, Rockville, MD, and Energy and Environmental Research Associates, LLC, Pittsford, NY. nyserda.ny.gov/publications. See page 130.

¹⁸ From NETL Reference 4.

the national average. Thus, it is appropriate, for this methodology, to assign the national average emission factor (with the appropriate 10% reduction for distribution losses) to spot gas purchases.

To return to the example, if the 644,000 Dth purchase was all undifferentiated gas, the calculation uses an emission factor of 28.4 g/MJ CO₂e, GWP 20. The GHG losses then total 19,297 metric tons CO₂e, GWP 20.

Figure 3 – NETL Methane Emission Rates



Advantages of this approach to production emissions accounting

There are several advantages to this methodology for quantifying upstream emissions. First, the calculation is straightforward and transparent, without unnecessarily complicated additional modeling. This methodology relies on the rigorous modeling conducted by the NETL, a world class research organization with a long history of gas industry modeling. By using NETL

data, the methodology can also remain current as the NETL publishes new data from their subsequent investigations.

Second, this methodology is based on actual purchases of discrete quantities of natural gas from known nomination points. It does not rely on derivations of gas quantities scaled from national data compiled by the Energy Information Agency (EIA). Each one of the Joint Utilities keeps accurate records of their gas purchases, making it possible to reconcile upstream emissions against total gas purchases in an auditable fashion.

Third, this methodology makes it possible to show the emissions reduction value of gas purchased as certified gas. An increasing amount of the gas supply in the United States is being delivered as certified gas¹⁹ and some of the Joint Utilities have approved pilot programs to purchase such gas. The Joint Utilities have a strong interest in evaluating the cost effectiveness of the emission reductions associated with purchases of certified gas, and this straightforward methodology allows any party to do so.

Finally, there has been a rapid increase in the application of new emissions monitoring technologies in the past several years. Producers are increasing the transparency of their actual emissions through programs such as OGMP 2.0, Project Veritas, and ONE Future. As these technologies and reporting paradigms become commonplace in the industry, the basin emission factors will become more accurate and can be incorporated into this methodology.

Comparison of this methodology to the approach in Part 496

In July 2019, New York State enacted the CLCPA. The CLCPA requires establishment of statewide GHG emissions limits as a percentage of 1990 emissions and requires the inclusion of

¹⁹ See, e.g., <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/011422-record-volumes-of-certified-gas-reaches-us-markets-after-bumper-year-of-commitments-in-2021>.

out-of-state emissions associated with the extraction and transmission of fossil fuels for consumption within New York State. This requirement necessitates using upstream fossil fuel cycle emission factor data that cover extraction, processing, and transmission/distribution of natural gas, coal, and petroleum into the State.²⁰

CLCPA also requires preparation of an annual statewide GHG emissions report. To complete the upstream emissions portion of the inventory, DEC relied upon research conducted by a consulting firm, the Eastern Research Group (ERG) (see reference in footnote, below). As in this methodology, the ERG Technical Document relied upon NETL modeling of upstream greenhouse gas emissions. However, to accomplish other public-policy related goals, ERG expanded upon the NETL framework:

The National Energy Technology Laboratory (NETL) Natural Gas model (NETL, 2019) assesses GHG emissions from natural gas extraction, processing, transmission, and distribution from U.S. natural gas basins. Upstream fuel cycle emissions for NYS are sourced from this bottom-up model in openLCA, an open-source life cycle modeling software application. However, the model simply serves as a starting point; available empirical data addressing areas of uncertainty in the wider natural gas literature body are integrated into the NETL model framework to develop regionally specific emission factors unique to this inventory. Among the areas of uncertainty this approach sought to address are skewed emissions from low-producing conventional gas wells (known as “super-emitters”) and uncertainty around shale gas emissions, as well as discrepancies in natural gas emissions reporting between bottom-up inventories and top-down measurements (both discussed further in Section 2.2.1.1). Adjustments are also made to the NETL model—which is reflective of 2016 conditions—to account for both changes in GHG emission intensity throughout the time series based on data from the U.S. GHG Inventory and variation in transmission distance to the New York border based on the location of the natural gas source basins.²¹

²⁰ This summary is derived from the following document: Eastern Research Group prepared for New York State Energy Research & Development Authority and New York State Department of Environmental Conservation, *Technical Documentation: Estimating Energy Sector Greenhouse Gas Emissions Under New York State’s Climate Leadership and Community Protection Act*. This document is referred to as “ERG Technical Document” in this section of the methodology.

²¹ See ERG Technical Document, Section 2.2.1, page 16.

Despite ERG’s assertion that its efforts resulted in “regionally specific emission factors unique to this inventory,” the result of their calculations led to DEC’s adoption, in Part 496, of a single emission factor for all upstream natural gas supplied to the State. Figure 4 below²² shows the generalized emission factor for all upstream natural gas supplies delivered to the State, as well as unitary upstream emission factors for all similar fuels.

Figure 4 – 2019 Emission Rates for Upstream Out-of-State Sources (g/mmbtu)

Fuel Type	CO2	CH4	N2O	Total CO2e
Natural Gas	12,131	357	0.14	42,147
Diesel/ Distillate Fuel	15,164	121	0.26	25,375
Coal	3,300	364	0.10	33,891
Kerosene/Jet Fuel	10,071	109	0.17	19,270
Gasoline (E85)	5,097	33	0.08	7,905
Gasoline	19,604	128	0.33	30,405
LPG	17,295	121	0.27	27,553
Petroleum Coke	11,612	112	0.20	21,096
Residual Fuel	11,799	111	0.19	21,184

Note: Total CO2e conversion uses GWP20 per 6 NYCRR Part 496.

The methodology described in this section adheres to the DEC methodology – being constructed on the extensive analysis of the NETL – but this methodology is singularly focused on the GHG emissions associated with each of the Joint Utilities’ gas systems. As such, it does not need to accomplish other goals (such as reconciling the differences between bottom-up and top-down inventories) nor does it need to incorporate concerns related to non-productive conventional wells, “super-emitters” and other larger issues associated with the natural gas industry *writ* large. The methodology described here is much more granular with a focus on single providers and gas supplies that have an emission rate certified by third-party auditors. The annual data submitted in

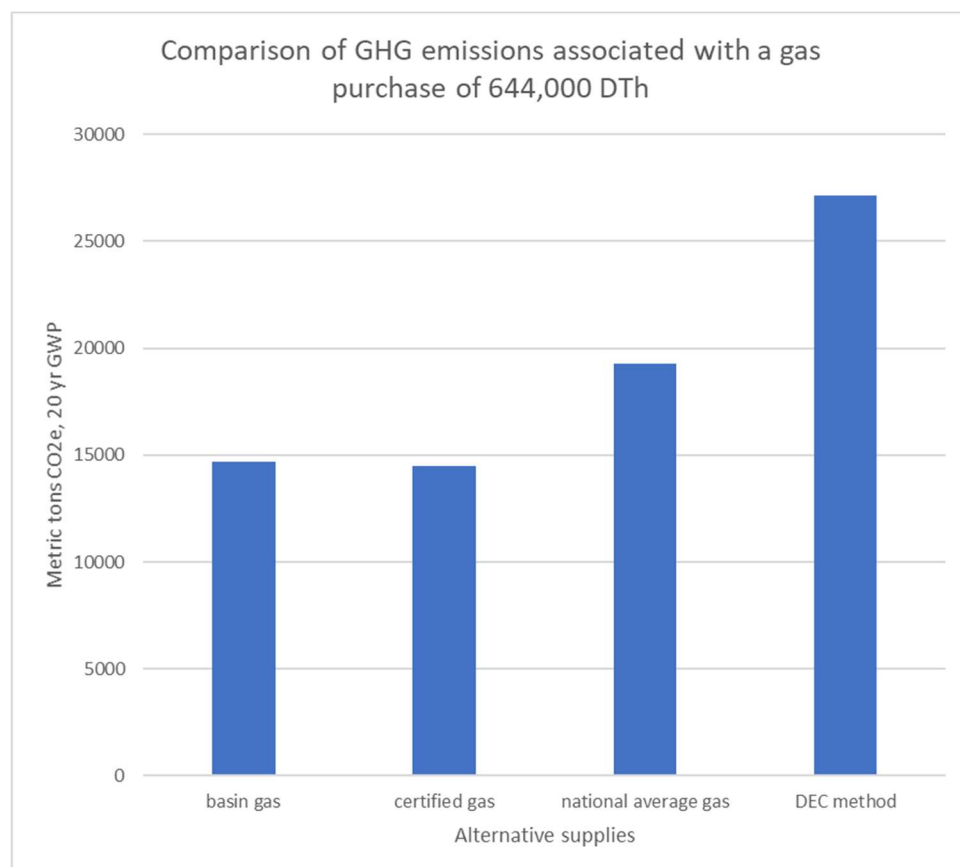
²² https://www.dec.ny.gov/docs/administration_pdf/ghgsumrpt21.pdf.

accordance with this methodology will be a valuable input to DEC’s ongoing efforts to identify statewide greenhouse gas emissions.

To complete the analysis, and the comparison between the methodology described here and the results of the DEC’s incorporation of ERG’s modeling work into a singular emission rate for all gas supplies, the “Total CO₂e” value for natural gas shown in the table above, 42,147 g/mmBtu CO₂e GWP 20, can be applied to the illustrative purchase of 644,000 in the following manner. Assuming 1 Dth is equivalent to 1 MMBtu, the total loss for 644,000 Dth (the example amount previously used) is 27,143 metric tons CO₂e, 20-year GWP.

Figure 5 below compares the four analyses:

Figure 5 – Example Gas Purchase Comparison



Incorporating changes to this methodology going forward

The natural gas industry is in transition. New emission detection technologies are under development, Federal regulations related to acceptable emissions from the oil and gas industry are under development, and the NETL continues to refine its life cycle assessment data. Data collection processes likely will continue to improve over time.

If such changes to the recommended methodology appear warranted, the Joint Utilities will bring the proposed changes to the attention of the DPS Staff for consideration. If any data assumptions or approaches are incorporated into the methodology with the concurrence of DPS Staff, they will be fully explained in the next annual filing of GHG inventory data.

IV. Annual Reporting Framework

The Joint Utilities propose to use a common reporting structure to facilitate aggregation and comparison across the State. Figure 6 below illustrates the various emissions sources that would be reported in the GHG Inventory (an Excel file is included as an attachment to the proposal and is intended to serve as an annual reporting framework). The inventory of emissions would begin at the customer meter, include all attributable and avoided emissions for the local distribution system, and further include upstream emissions attributable to the import of natural gas using the approach described in the previous sections.

Figure 6 – Proposed Annual Reporting Framework for GHG Inventory

Natural Gas System Greenhouse Gas (GHG) Emissions Inventory Report				
EMISSION TYPE	SOURCE	CALCULATION METHODOLGY	REPORTING UOM	ANNUAL TOTAL
End-Use (Customer Meter)				
Fugitive	Residential Meters (outdoor)	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Commercial/Industrial Meters	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Note: the JU propose that emissions at the customer meter are the end boundary for the GHG Inventory (i.e., the GHG Inventory would not include post-meter emissions from customer combustion).				
Local Distribution System				
Attributable Emissions	NGSI Protocol			
Combustion	Combustion Units*	As reported to GHGRP	MT CO2-e, 20-yr GWP	
Fugitive	Distribution Mains, total	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Cast Iron	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Unprotected Steel	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Protected Steel	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Plastic	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Plastic Liners or Inserts	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Copper	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Ductile Iron	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Other	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Distribution Services, total	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Cast Iron	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Unprotected Steel	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Protected Steel	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Plastic	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Plastic Liners or Inserts	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Copper	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Ductile Iron	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Other	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Fugitive	Equipment Leaks, total	As reported to GHGRP	MT CO2-e, 20-yr GWP	
Fugitive	Above grade transmission-distribution transfer stations	As reported to GHGRP	MT CO2-e, 20-yr GWP	
Fugitive	Below grade transmission-distribution transfer stations	As reported to GHGRP	MT CO2-e, 20-yr GWP	
Fugitive	Above grade metering-regulating stations	As reported to GHGRP	MT CO2-e, 20-yr GWP	
Fugitive	Below grade metering-regulating stations	As reported to GHGRP	MT CO2-e, 20-yr GWP	
Vented	Vented Emissions, total	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Vented	Blowdowns, Distribution pipeline	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Vented	Damages (Distribution Upsets: Mishaps)	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
Vented	Pressure Relief Valves, Routine maintenance	NGSI w/ GHGI EFs	MT CO2-e, 20-yr GWP	
* Combustion units include external fuel combustion units (e.g. heaters, industrial boilers, commercial and industrial combustion units) with a rated heat capacity >5 MMBtu/hour and internal fuel combustion units (e.g. gasoline or diesel industrial engines, reciprocating engines, gas turbines) with a rated heat >1 MMBtu/hour (or the equivalent of 130 hp).				
Avoided Emissions	Possible Approaches			
	Use of renewable fuels			
Fugitive	Enhanced leak response time			
Fugitive	Reduced leak backlog			
Vented	ZEVAC use/blowdown reduction			
Vented	Dig-in reductions			
Note: there is currently no commonly accepted protocol in the natural gas industry that is applicable for reporting avoided emissions. For this reason, the Joint Utilities propose that the Commission allow flexibility in how the Joint Utilities report avoided emissions.				
Upstream				
Imported Gas	NETL Emissions Factors			
Fugitive/Vented/Combustion	Undifferentiated gas ("base gas")	NETL National Average EF	MT CO2-e, 20-yr GWP	
Fugitive/Vented/Combustion	Gas from a known basin	NETL Basin-Specific EF	MT CO2-e, 20-yr GWP	
Fugitive/Vented/Combustion	Certified gas	EF Based on Certification	MT CO2-e, 20-yr GWP	

It is important to consider how evolving measurement technologies could enhance these approaches in the future. For example, in terms of attributable emissions, it may be possible in the future to develop service territory-specific emission factors, which would improve the accuracy of

LDC-level reporting. In terms of avoided emissions, there may be better quantification to ZEVAC values or more precise emission factors for Type 3 leaks, as examples. For these reasons, it is important to consider that the approaches set forth in this proposal could be improved in the future with technological innovations and potential methodological enhancements.

V. Summary and Conclusion

The Joint Utilities proposal for an annual GHG Emissions Inventory provides for annual reporting of emissions associated with natural gas distribution systems in the following three categories:

- Attributable emissions, including emissions from utility customer meters;
- Avoided emissions, where specific activities of a utility may cause measurable emissions reductions; and
- Upstream emissions, resulting from the import of natural gas into the State.

The Joint Utilities consulted with DPS Staff during the development of this proposal. This proposal satisfies all requirements of the Order and follows the methodology required in the CLCPA and by DEC.

Appendix A

The table below is derived from the NETL Reference 1, Exhibit F-1 on page F-3. It shows the adjustment to the emission factor (in g/MJ) for Appalachian-supplied gas with a specific emission rate ascribed to a certified gas product.

NETL Reference 1 Exhibit F-1

	A	B	C	D
1	Emission		Production	
2		P2.5	Mean	P97.5
3	Carbon dioxide	3.92E-04	1.36E-03	2.37E-03
4	Methane	1.72E-05	2.10E-05	2.59E-05
108				
109	Delivered natural gas		1.75E-02	kg/MJ
110	Current production fugitive methane emission rate	=C4/C109	0.12%	kg CH4 emitted/kg NG delivered
111	Desired methane emission rate		0.10%	kg CH4 emitted/kg NG delivered
112	Adjusted methane emissions	=C111*C109	1.75E-05	kg/MJ
113	Difference	=C4-C112	3.49E-06	kg CH4/MJ
114		=C113*87*convert (1,"kg","g")	3.03E-01	g CO2e/MJ
115	Previous Cradle-to-gate GWP		24.1	g CO2e/MJ
116	Adjusted cradle-to-gate GWP		23.75758	g CO2e/MJ

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Respectfully submitted,

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